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A PRICING MODEL FOR A NATURAL GAS TRANSMISSION SYSTEM

by

TOBY McLEAN SYMES

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE

OF MASTER OF BUSINESS ADMINISTRATION

FACULTY OF BUSINESS ADMINISTRATION AND COMMERCE

EDMONTON, ALBERTA

FALL, 1970

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UNIVERSITY OF ALBERTA

FACULTY OF GRADUATE STUDIES

The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled A PRICING MODEL FOR A NATURAL GAS TRANSMISSION SYSTEM submitted by TOBY McLEAN SYMES in partial fulfilment of the requirements for the degree of MASTER OF BUSINESS ADMINISTRATION.

ABSTRACT

This study is concerned with the generation of prices to be charged to customers by a natural gas transmission system out of storage. Five models, pertaining to different types of storage, are covered. The study uses data supplied for a particular corporation located in the Southern United States, and consequently the specific results have the greatest application within this company. Hopefully, it has a wider use and may be applied to any transmission corporation. The general model is a linear programming model, so used because of its ability to generate quick accurate solutions. The problems associated with pricing for interstate transmission companies are many and varied. In particular, there is the problem of time lag between a rate application and its enforcement, primarily because of the legal requirements to be met and data to be furnished to the controlling body, the F.P.C. This study hopes to shed new thought on the method of arriving at prices by applying the model to another of the associated problems, that of storage prices. The study covers the aspects of storage, pricing regulation, and economic advantages.

ACKNOWLEDGEMENTS

The author would like to thank the members of his Committee for the time and effort they so generously donated leading to the culmination of this study. In particular, to Dr. Boyd M. Harnden, the Chairman of the Committee, the author wishes to extend sincere thanks for his patience and inspiration concerning both the material aspect and the learning technique involved. To Dr. Peter Winters and Dr. Max Stewart is extended a sincere appreciation.

The author would also like to thank the Southern Natural Gas Company of Birmingham, Alabama, for their assistance in providing the data upon which the study was based. Without this, it is felt that a realistic study could not really be undertaken.

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CHAPTER I

INTRODUCTION

Objective

The primary purpose of this dissertation is to develop a mathematical model which can be used as a guideline to establishing the price at which natural gas can be sold out of storage by a gas transmission corporation. The model may be applied for internal decision making purposes either to act as a price setting weapon or as a check on the existing prices which are operational.

The second objective of the research is to provide a means of analysis which can lead towards optimal system operation. Once the prices are generated from the model then these can be reincorporated as the coefficients of the variables to determine what quantity of gas should be sold and in what market. Following this some parametric programming may be undertaken in order to view the model over a pre-specified time period.

An Overview

There has been a considerable amount of work published about natural gas transmission systems, both technical and economic. This paper will consider the economic aspect rather than the technical.

In the area of pricing for storage systems, the price at which gas is sold is regulated by Federal control for the principal consumer--the public utility. The method of regulation is known as rate making.

(This will be explained in Chapter IV.) It is a comparatively complicated procedure by which the price of gas is determined. Authors such as Garfield and Lovejoy,[1] Eli Clemens,[2] and Bryant and Herrmann[3] elaborate in detail over the intricacies of the requirements in addition to pointing out the major advantages and disadvantages of such a system.

It is common knowledge within the natural gas industry that an application made by a transmission company to the Federal Power Commission (the controlling body) for a rate change or a rate settlement usually takes a considerable period of time principally because of the requirements. This study hopes to stimulate new thoughts which may lead to acceleration of the process, and at the same time be accurate and equitable.

The storage of natural gas is becoming more and more a compulsory requirement for the survival of a transmission system because of the nature of competition and the tight regulatory constraints. This being the case, writers have become more aware of the economic implications attached to possible types of storage installations. The types range

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[1] P. J. Garfield and W. J. Lovejoy. "Public Utility Economics", Prentice Hall, Englewood Cliffs, New Jersey, 1964.

[2] E. W. Clemens. "Economics and Public Utilities", Appleton-Century-Crofts Inc., New York, 1950.

[3] J. M. Bryant and R. R. Herrmann. "Elements of Utility Rate Determination", McGraw-Hill Book Company Inc., New York, 1940.

from the expected, for example dried-up oil fields, to the unexpected, for example to the creation of a storage cavity by nuclear explosion. Witherspoon and De Pasquale[1] completed a study on the economics of underground gas storage in cavities created by nuclear explosives; and Harnden[2] looked into the economics of aquifer storage.

Linear Programming (L.P.) is a powerful analytical tool and an increasing number of applications are being discovered for its use. In the natural gas industry, authors such as Dantzig[3] and Hax[4] have applied L.P. models to optimize pipeline system operations. However, neither of these studies concerned themselves with storage. In the former case, storage demands of gas were known and in the latter, storage volumes remained constant. This study will concern itself entirely with storage and provided that pipe line capacity will exceed storage capacity, the problems of pipe line operation will not be discussed.

---

[1]P. A. Witherspoon and D. L. De Pasquale. "Economics of Underground Gas Storage in Cavities Created by Nuclear Explosives", College of Engineering, University of California, Berkeley, July, 1968.

[2]Boyd M. Harnden. "A Simulated-Neuristic-Long Range-Planning-Storage Model for a Natural Gas Transmission System", University of California, Berkeley, May, 1968.

[3]G. B. Dantzig's Out-of-Kilter Algorithm presented in Richard M. Van Slyke, "Network Flow Models of Natural Gas Transmission Systems", Operations Research Center, University of California, Berkeley, August, 1965, and reported by B. M. Harnden, op. cit., p. 9.

[4]Arnoldo Hax. "Natural Gas Transmission System Optimization: A Mathematical Programming Model", Operations Research Center, University of California, Berkeley, May, 1967.

CHAPTER II

THE MOTIVATION FOR THE MODEL

Physical Characteristics

The operations of a large natural gas transmission system may typically be represented by those of the Southern Natural Gas Company located in Birmingham, Alabama. The general system map is shown in Figure 1 on page 5. The company as of 1967[1] owned 6,212 miles of pipe line stretching across seven states. Approximately 342,000 horsepower of compressor facilities were utilized in transmitting in excess of $160 million of natural gas to the markets.

The Supply of Natural Gas

The raw materials for this system are found in southern Louisiana and Mississippi and the prime markets are located in Alabama, Georgia and South Carolina. The method of acquiring the raw materials used by Southern is typical of that of the rest of the industry. According to its 1966 Annual Report, the company owned only 8% of its gas reserves,[2] the other 92% being purchased on a contract-take method from oil and gas exploration companies who held the respective leases.

In explanation of the contract-take method, a transmission company will undertake to withdraw a specified volume of gas each

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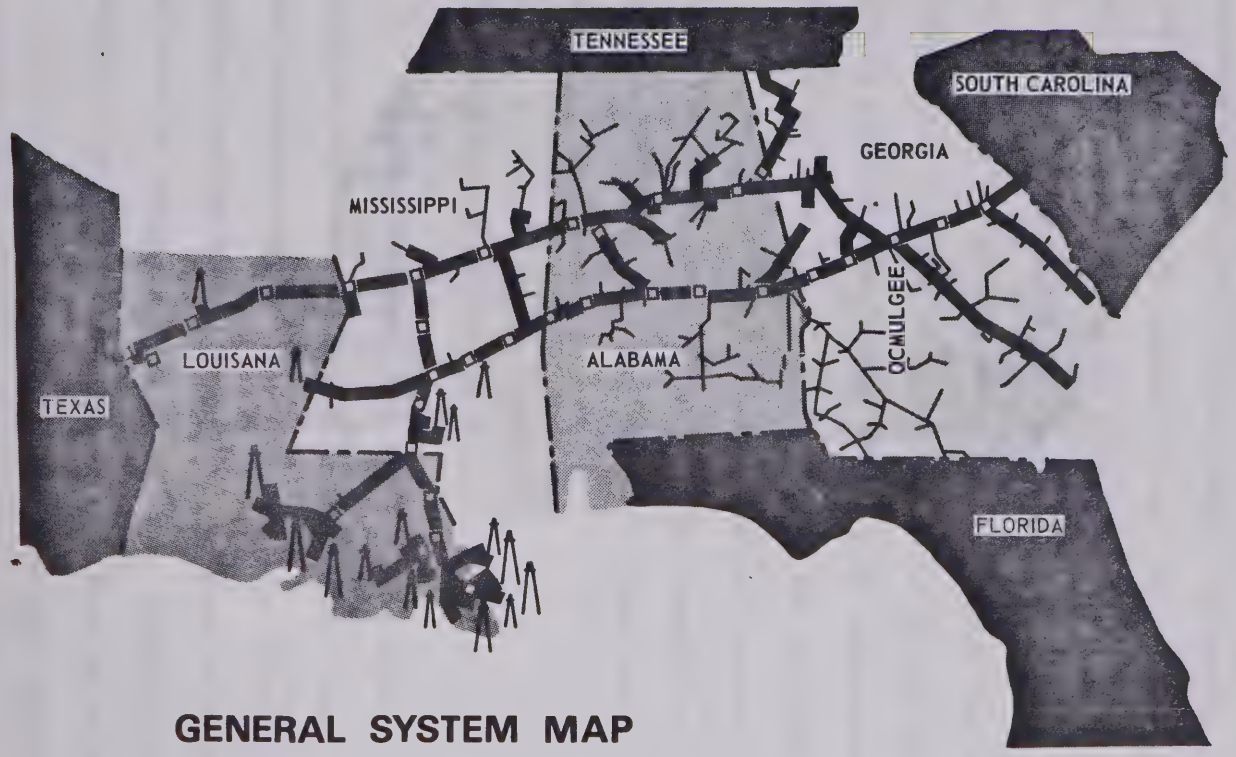
[1] Southern Natural Gas Company, Birmingham, Alabama, 1967 Annual Report, p. 15.

[2] Southern Natural Gas Company, Birmingham, Alabama, 1966 Annual Report, p. 17.



GENERAL SYSTEM MAP
1967

FIGURE NO. 1

month over the term of the contract. The company will pay for this gas regardless of whether it "takes" it or not. Because the lessor controls the outflow at the well-head, the company cannot draw more than 100% of the specified monthly volume. So, the per unit cost of gas will increase if 100% is not withdrawn in any one month.

The prime reason why the transmission companies purchase most of their gas rather than own it is that, while they stand to make a greater profit margin on successful wells through obtaining gas at a reduced per unit cost; in the event of an unsuccessful well the exploration costs cannot be included in the rate base which determines prices. As the cost of purchasing the gas from suppliers is included in the rate base, then, why should the transmission companies take risks to find their own gas, especially since the selling price is fixed!

The System

The general system, such as that of Southern, covers several rate zones which are designated by the Federal Power Commission (F.P.C.). These are approximately located as, firstly, covering the states of Louisiana and Mississippi; secondly, the state of Alabama; and thirdly, the states of Georgia and South Carolina. Zoning was introduced to consider variable transportation costs. This led to effective control by the F.P.C. over area prices for natural gas. The prices which may be charged differ as between zones for two reasons. Firstly, they differ due to the differences in transmission costs, and secondly,

according to the amount of energy reserves available in those zones. In Louisiana, for example, there is no coal[1] and in Georgia and Alabama only limited deposits of coal and water and no gas (refer to Figure 2, p. 9).

The major point of emphasis from this, is that the rate of return on investment which the transmission company can receive is fixed by Federal Control. The return, according to Harnden,[2] is about 7 per cent of the rate base. The "rate base" refers to the total net value of the company's tangible and intangible capital applied directly to the making of the sale of gas.[3]

The prices are also reasonably inflexible due to the competitive nature of natural gas. They must be no more expensive than what is charged for coal, oil, and hydroelectricity in each area. The transmission company must be able to ship gas efficiently enough not to exceed this upper bound on price.

However, complications arise to the extent that the transmission company must lay sufficient pipe line in order to be able to meet what is known as the peak demand. Peak demand requires the system to operate at peak capacity. According to Harnden and Witherspoon,[4] the system

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[1] E. W. Clemens, op. cit., p. 316.

[2] B. M. Harnden, op. cit., p. 17.

[3] P. J. Garfield and W. F. Lovejoy, op. cit., p. 56.

[4] B. M. Harnden and Paul A. Witherspoon. "A Planning Model for Evaluating Effect of Storage on Natural Gas Transmission Systems", Society of Petroleum Engineers of AIME, Texas, 1969, p. 8.

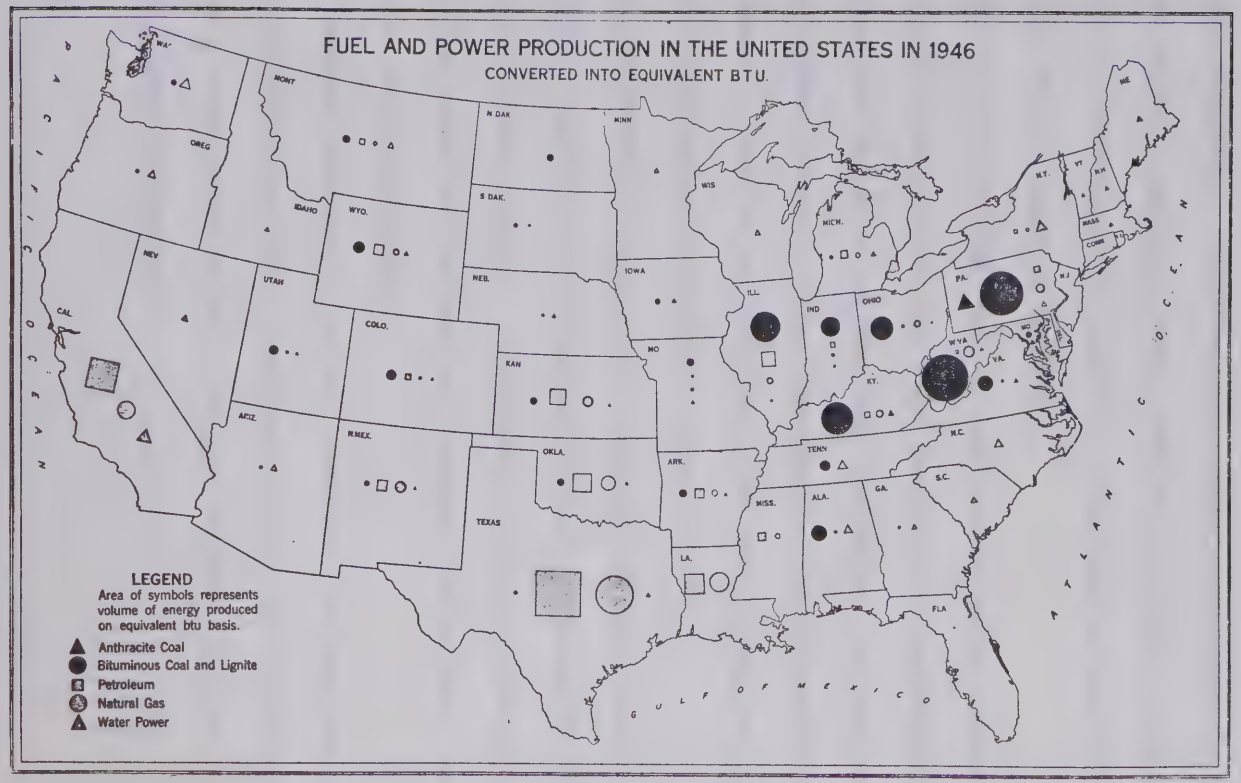
FUEL AND POWER PRODUCTION IN THE UNITED STATES IN 1946
CONVERTED INTO EQUIVALENT BTU.
LEGEND
Area of symbols represents volume of energy produced on equivalent btu basis.
Anthracite Coal
Bituminous Coal and Lignite
Petroleum
Natural Gas
Water Power
WASH.
OREG.
CAL.
NEV.
IDAHO
MONT.
WYO.
UTAH
ARIZ.
COLO.
N.MEX.
N.DAK.
S.DAK.
NEB.
KAN.
OKLA.
TEXAS
MINN.
IOWA
MO.
ARK.
LA.
WIS.
ILL.
MICH.
IND.
OHIO
KY.
TENN.
MISS.
ALA.
GA.
FLA.
S.C.
N.C.
VA.
W.VA.
PA.
N.Y.
ME.
VT.
N.H.
MASS.
CONN.
R.I.
N.J.
MD.
DEL.
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO

Figure 2

is said to be operating at peak capacity when it is delivering an amount of gas equal to the forecasted jurisdictional requirement for which it was designed. A day when the system is operating at peak capacity is called a peak day. Any other day is called on off-peak day. Figure 3 on p. 9 shows how the number of peak days is expected to increase and off-peak days to decrease.

From this evolves the idea of load factor, which refers to the measure of pipe line utilization. The load factor represents the total amount of gas delivered during the year divided by the total possible throughput volume. Because pipe lines must be constructed to serve the peak demand, which occurs only for a few days during the winter months, the load factor is typically quite low.

The transmission company will lay pipe line according to the specifications suggested by the jurisdictional customers which are designed to meet peak demand. The reason for this is that the utility company in fact pays for the cost of the pipe line in their contractual price for gas on a usage basis.

It becomes intuitively obvious from this that the more gas that is shipped along the pipe line, the lower is the capital charge per M.C.F. of gas. As a consequence of this, the gas industry desires to obtain as high a load factor as possible.

The Market

At the market end of the system there are basically three types of customers who are served by the transmission company. These are:

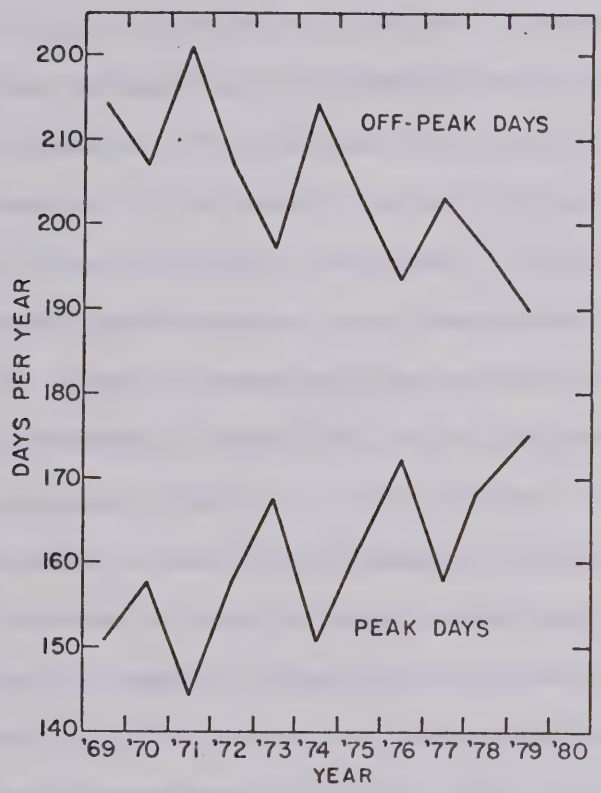

Fig. 3: Projected Number of Peak and Off-Peak Days for a Hypothetical System.

(1) Jurisdictional customers, i.e., public utility companies. These clients are the largest of those served typically representing about 96 per cent of the total consumption.[1] They are "uninterruptible" to the extent that their requirements must be satisfied over and above any other customers. The price for this privilege is that the control over gas prices is regulated by the F.P.C.

(2) Jurisdictional-Direct customers. These are industrial customers who purchase their requirements through the localized distribution systems. They represent only about .02 per cent of the total consumption.[2] The price of gas is not regulated because it must be directly competitive with other fuels. If the utility company does not sell at a competitive price then these customers would switch to coal or oil. These customers are interruptible as far as the utility company is concerned, although this is not the case from the position of the transmission company. In fact, they are the equivalent of the Direct customers for the utility companies. However, they generally purchase their gas at slightly higher prices than do the true direct customers as the amount of "dump" gas available to them is less than that to the true direct. In return they receive better, more firm service than do their counterparts.

(3) Direct Customers--are those clients who purchase their requirements directly from the transmission company. They are

---

[1] Southern Natural Gas Company. "Application under section 7 of the Natural Gas Act"--Volume 2, Exhibit I, Pts. (i) - (viii) F.P.C. Docket, No. CP69-178, p. A.

[2] Ibid.

industrial-type customers. Generally they are interruptible[1] and unregulated and are compensated for this by a low purchase price for their gas requirements. In fact the price charged to these clients is the cost of gas plus the transmission costs and a profit margin. They do not share the capital cost of the pipe line with the jurisdictional customers. This in turn has led to conflict between the utility companies and the transmission companies over whether the transmission companies should have the right to sell gas to direct customers.

The Limitations

The transmission company desires to sell as much gas as possible within pipe line capacity, at a competitive price and obtain, at the same time, the allowable return on the rate base. Within a regulated industry this requires efficiency of operations. Specifically, a high-load factor operation is required. To overcome this problem, there are two solutions. Firstly, the installation of a storage system either at the market end of the pipe line, or at both ends may be an economic proposition. At the source end (for example, Louisiana), a storage facility could be installed to ensure the maximum removal of gas from the wellhead, and this even out any price differential in the cost of gas under the contract-take method.

At the market end storage facilities of several types, depending on the physical and geological structure of the area, may be installed.

---

[1]Refers to a contractual agreement under which supply to the customer may be interrupted from time to time when demands from firm customers are considerable.

Its purpose would be to absorb gas during the summer months to continue operating the pipe line at 100 per cent load. This would reduce the per unit cost of gas at the market by virtue of the fact that the associated costs on the gas would be spread over a greater volume. In the winter months this gas would be used for peak shaving[1] and to firm up the demand requirements of direct customers. Over the long run, this service would put back the installation of new pipe lines for an increased demand, and the monies thus saved could be applied to other investment.

The second solution is to develop, through various incentives, a greater number of direct customers. As these clients are classified as interruptible a higher load factor operation can be obtained by providing them more gas in the summer months when the source is available, thus even out the annual overall demand for gas. However, the associated problem with this is the reduced per unit profit on the gas. On the other hand, there is always the argument that a customer can be expected to pay more where his demand is 'firmed-up'. But the writer is of the opinion that this instance is not really equivalent to firming up the interruptible customers' requirements; rather, it leads to the opposite situation--an increase in the volume of interruptibles for a shorter time span.

The Problem

Of these two solutions, the idea of storage installation is more

---

[1]Refers to supplying gas to the demand area known as the peak block (see Figure 4, Chapter III, p. 21).

appealing. But there are many different types of storage alternatives depending on the geological structure of the area selected for the installation. In the case for the Southern Natural Gas Company, at the market end of the system, the structure implies the installation of a Liquid Natural Gas plant, an aquifer, a cavity created by nuclear explosion, or combinations of these.[1]

This paper is concerned about the economics of each alternative considered, and the 'best' prices that can be attributed in each case to each customer for each rate zone. By 'best' is understood as the maximum that can be charged which does not conflict with competitive prices on the one hand and legal regulation on the other.

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[1]Boyd M. Harnden, op. cit., pp. 58-72.

CHAPTER III

THE STORAGE OF NATURAL GAS

The Basic Advantages of Storage

The natural gas industry installs storage facilities at the market area for a variety of reasons, which include the following:

(i) The achievements of a high load factor operation to reduce the overall cost of service to customers.[1]

(ii) The ability to level out cyclic fluctuations in the demand for gas caused by temperature variations.[2]

(iii) An improved service to both jurisdictional and industrial customers.[3]

(iv) The maintenance of market share with respect to competition from other energy sources.[4]

(v) The provision of a cushion against line breakage.[5]

(vi) A larger proportion of the natural gas purchased can be sold for household purposes.[6]

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[1] Harnden and Witherspoon, op. cit., p. 1.

[2] Ibid.

[3] Ibid.

[4] Ibid.

[5] Ibid.

[6] The Natural Gas Industry, Department of Defense Production, Ottawa, May 1951, p. 74.

(vii) Less gas needs to be sold on an interruptible basis or dump-sale purposes.[1]

Of these advantages, probably the most important are the first two. If these are exploited, then the opportunity is opened up to develop those remaining.

The Economic Motivation for Storage

In the United States, most of the natural gas that is consumed is produced in central regions of the country that are typically remote from the market areas. (With reference to the map on page 9, consider the deposits in relation to the large consumer markets of the eastern seaboard.) The system requires the installation of high pressure pipe lines up to a thousand or fifteen hundred miles in length to transport the gas. A large capital investment is required for such a system. The justification for the investment is that the system operate as close to maximum capacity as possible throughout its useful life. Once the physical system has been installed, the costs of operation are more or less fixed; it costs little more to transport gas at the maximum capacity than it does at some lower capacity. This means that the fixed cost of the investment is spread over a large volume of gas and that near maximum capacity, an increase in demand will result in an increase in costs which are predominantly variable. The controlling economic factor in recovering the investment becomes the load factor.[2] By way of example:

---

[1] Ibid.

[2] Witherspoon and De Pasquale, op. cit., p. 8.

> . . . the Michigan Consolidated Gas Company receives gas from Texas and South Louisiana pipelines which cost one-quarter billion dollars and operate at 100% load factor. The underground storage plant owned by this company cost one-fifth of this amount but handles 30 per cent of the gas transmitted to market and satisfies 59 per cent of the peak-day demand. Investment costs for 1 M.C.F.D. (Thousand Cubic Feet per Day) of pipeline capacity vary from $200 to $500, while underground storage investment is only about $50/M.C.F.D. capacity.[1]

Resulting from the notion of a high load factor requirement is the establishment of a contractual form of sale for gas. This contract, which is regulated through the F.P.C., is basically constructed of two charges: the demand rate and the commodity rate. The demand rate is designed to recover the fixed costs on a daily basis, over a pre-specified period of time. This charge must be paid by the purchaser regardless of whether any gas is taken or not. The commodity charge includes the cost of gas, normally calculated under the contract-take method, and the operating transmission costs.

The impact of such a structured rate on a gas utility corporation without storage facilities can be quite considerable. The utility must be able to meet the maximum anticipated demand for the coldest day of the year, yet pay substantial sums during the summer when the demand requirements are minimum. Demand requirements do fluctuate considerably with the weather pattern. In the Chicago area, for example, demand might fluctuate as much as two billion cubic feet per day. In

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[1]Keith H. Coats. "Some Technical and Economic Aspects of Underground Gas Storage", Reported in Natural Gas--Proceedings of a Symposium held by the Exploration and Production Group of the Institute of Petroleum. London, 17 June 1966, p. 81.

Southern California, the residential consumer may use up to seven times as much gas on a cold winter day as he will use on a summer day.[1] The effect of this on the average cost of gas can be quite substantial, especially if the local utility company is operating with a very low load factor, which may often be the case.[2]

Witherspoon and De Pasquale[3] cite an example on pp. 8 and 9:

> . . . let us consider a utility company that has a peak day requirement of 100,000 M.C.F. and operates with a 30 per cent load factor, i.e., it can only sell 30 per cent of its annual supply. We shall assume the demand rate is $3.00 per M.C.F. and the commodity rate is $0.30 per M.C.F. with no 'take or pay' clause. Under the above conditions, the company would have to pay $6,885,000 for 10,950,000 M.C.F. annually, or an average cost of $0.629 per M.C.F. With an appropriate volume of gas storage the load factor might be increased to 90 per cent, in which case, the company would have to pay $13,455,000 for 32,850,000 M.C.F. annually or an average cost of only $0.409 per M.C.F. The use of storage could therefore reduce the basic cost of the pipeline by 36 per cent.

The motivating factors apply not only to utilities but also to the transmission companies. The reason for this is that the majority of the transmission companies' sales of gas are to the utility companies (see page 10). This being the case, then, the transmission companies' prices both for the purchase and the sale of gas are controlled by external forces. These controls imply the

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[1] Boyd M. Harnden. A Dissertation Proposal, University of California, Berkeley, May 1968, p. 2.

[2] C. J. Gauthier. "Economics of Gas Storage Operations to a Natural Gas Distribution Company" cited by Witherspoon and De Pasquale, op. cit., p. 8.

[3] Ibid., pp. 8-9.

justification for storage.

The position with respect to the corporation under study is that it operates on a demand curve such as that shown in Figure 4 on page 21. In the figure, the distribution systems connected to the company are obliged to meet the demand in the peak block below approximately 64°F., from sources such as storage and purchases from competitors.[1] The transmission company is obligated only to supply the volume contracted to jurisdictional and firm-direct customers. But there is an opening to supply in the peak block to increase revenue and stabilize customer service. If this line of action is pursued, then the company will not only be able to face its competitors more strongly, but also it stands to make a material gain.

The Cost of Storage

The cost of installing and operating a storage facility is dependent on the following:

(1) The type of installation under consideration whether above or below ground,

(2) The physical delivery capacity, and

(3) The location for the installation.

In conjunction with these associated costs, for decision-making purposes, what is really relevant are those costs which are allowed to

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[1] B.M. Harnden. A Simulated-Heuristic-Long Range-Storage-Planning Model for a Natural Gas Transmission System, University of California, Berkeley, 1968, p. 74.

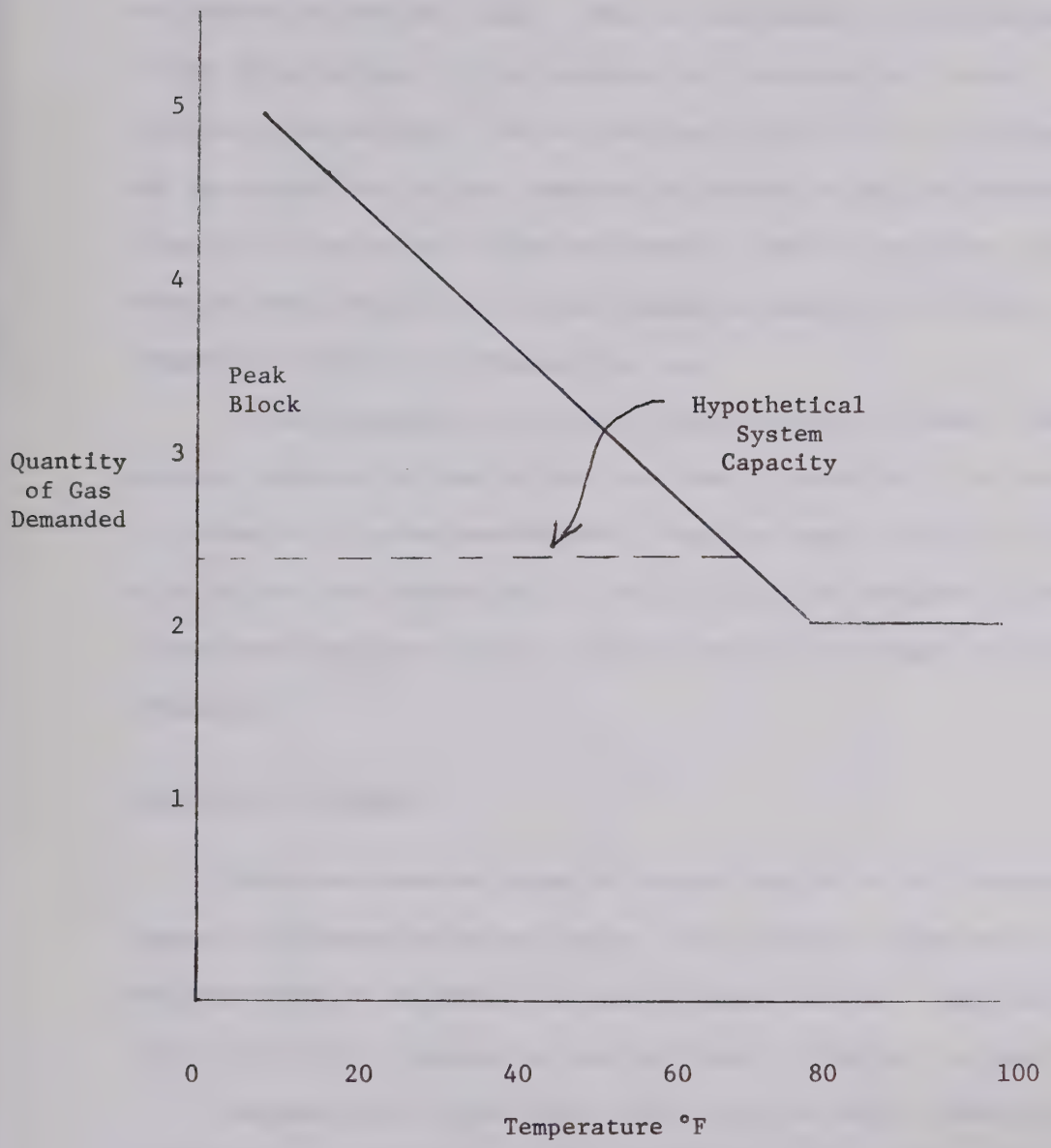

Fig. 4.[1] Typical Demand Curve Faced by a Transmission Company.

[1] Ibid., p. 73.

be included in the rate base. This in turn depends on the purpose of the installation. If the purpose is to service only direct customers from storage, then no costs are allowed in the rate base, for why should the utility companies be forced to pay for something from which they do not derive any benefit? At the same time the storage costs should be efficient enough to enable a profitable yet competitive price to be charged for gas.

If the purpose is to service jurisdictional customers then the storage costs are allowed in the rate base. Essentially, if the purpose of storage is to serve peak shaving, then the costs should be allocated on a 100 per cent demand basis. Costs of storage designed to provide a year-round service should be divided between the demand and commodity categories.[1]

The Types of Storage

There are numerous types of storage available to a transmission company both above and below ground. For Southern a Simulation Study was undertaken to determine the most economic choice.[2] The choices, ranked in order of decreasing cost are shown on Table I on page 23.

Depleted oil or gas fields are by far the most economic storage facilities in operation in the United States today, principally because of the lesser cost involved. Of the 278 storage reservoirs at the end

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[1] Ibid., p. 17.

[2] Ibid.

TABLE I

STORAGE ALTERNATIVES

	Below Ground	Above Ground	Market Storage	Supply Storage
1. Liquid Natural Gas (L.N.G.)	*	*	*	
2. Nuclear Cavities (formed by underground nuclear explosion)	*		*	
3. Underground Aquifers (a gas bubble created in a natural geologic reservoir containing water)	*		*	
4. Depleted oil or gas fields	*			*
5. The Pipe line itself		*	*	*

of 1963, 232 were dry gas, 12 were oil and gas reservoirs, 5 were oil reservoirs, and 28 were aquifer storage fields.[1]

However for Southern this form of storage is not available at the market end of the system in Alabama and Georgia, so the study was concentrated on other alternatives.

The Economics of Storage in an Underground Aquifer

An underground aquifer is created by pumping gas down into the anticline of an artesian basin thereby forming a gas bubble. Delivery capacity is probably the most important consideration in designing a storage reservoir of this type. For a given number of wells, the delivery rate is proportional to reservoir pressure, which, in turn, is proportional to gas in place.[2]

Hence, with an economic aquifer a higher proportion of gas can be extracted. This is directly reflective on the per unit storage charges. Where there is high deliverability then the per unit cost is lower and vice-versa.

In the simulation study[3] undertaken for Southern for an aquifer alternative, the assumptions were:

(1) Gas could not be withdrawn from the aquifer until the second year of operation.

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[1] Coats, op. cit., p. 76.

[2] Ibid., p. 75.

[3] Harnden, op. cit.

(2) Only approximately 50 per cent of injected gas could be removed; the remainder of the gas to remain as a cushion.

Resulting from this, the required price to be charged for a total deliverability of 380 M.M.C.F.D. and a total storage capacity of 90,000 M.M.C.F. was $0.46 per M.C.F., based on the present value of the forecasted net cash flow with a weighted average cost of capital of 10 per cent used as the discount factor.

The Economics of Storage in a Nuclear Cavity

One possible application of nuclear explosives is to create roughly cylindrical chimneys of rubble and void capable of storing large quantities of fluids at safe distances below the surface.[1] The beauty of this type of storage over aquifer is that the location of the installation is not dependent on the geologic existence of sedimentary rocks.[2] The most desirable environment is probably a thick-nonfractured shale sequence.[3]

For Southern, the installation of nuclear storage would mean the following:[4]

(1) Gas could not be withdrawn from storage until after five years of operation.

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[1] Witherspoon and De Pasquale, op. cit., p. 10.

[2] Harnden, op. cit., p. 64.

[3] Ibid.

[4] Ibid.

(2) Only approximately 90 per cent of total gas injected could be recovered.

(3) The price required for a total deliverability of 146 M.M.C.F.D. and a total storage capacity of 3,000 M.M.C.F. was $1.10 per M.C.F. based on the present value of the net cash flow.

The Economics of Storage in an L.N.G. Plant

Natural gas can be liquified and stored either above or below ground in a pre-stressed concrete tank. The main advantage of liquification is that more gas can be stored in the same tank at a similar pressure in PSIG. This in turn brings about obvious savings in land requirements and construction costs.

In addition, an L.N.G. plant can be located right at the market area itself. The piping required to ship gas from storage to clients is only a small portion of that required by other storage alternatives. However, L.N.G. carries with it certain disadvantages. Firstly, the cost of the installation in terms of removable gas is more expensive than for other alternatives.[1] In addition, there are boil-off costs when regasification is required. A further disadvantage of L.N.G. storage is the comparatively slow liquefaction and vaporization times.

The result for L.N.G. in the simulation[2] required a price to be charged at $1.16 per M.C.F. for a total deliverability of 200 M.M.C.F.D.

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[1] Ibid.

[2] Ibid.

and a total storage capacity of 3,000 M.M.C.F., based on the present value of the net cash flow. The assumptions were that:

(1) Gas could not be withdrawn from storage until the third year of operation, and

(2) Only 98 per cent of total gas injected could be recovered, the other 2 per cent being "lost" in liquefaction and vaporization.

CHAPTER IV

THE PRICE OF NATURAL GAS

The Position Prior to Regulation

Prior to 1938 there was no effective legal control over the prices charged for the sale of natural gas by interstate transmission companies. The prices of gas were regulated only by the demand for gas and the competitive prices of other fuels. But natural gas was considered (and still is) as a highly valuable and exhaustible natural resource. The increasing demand for gas led to the formation of monopoly pricing.

In a monopoly, the seller controls the output and no other firm has an opportunity to enter his market. By adjusting output and price, the seller can maximize his earnings. This is shown in Figure 5 on page 29. The monopolist extends production to the point where marginal revenue is equal to marginal cost (at P_1Q_1). If a higher price is charged and a smaller output is produced the company still obtains a monopoly return (at P_2Q_2). But this is not an optimal position because marginal cost is less than marginal revenue.

According to McKie,[1] under monopoly, the market process does not lead to optimum economic allocation. If unrestrained, monopoly produces artificially high prices, excessive profits, deficient investment, and a slow rate of exploitation of natural resources.

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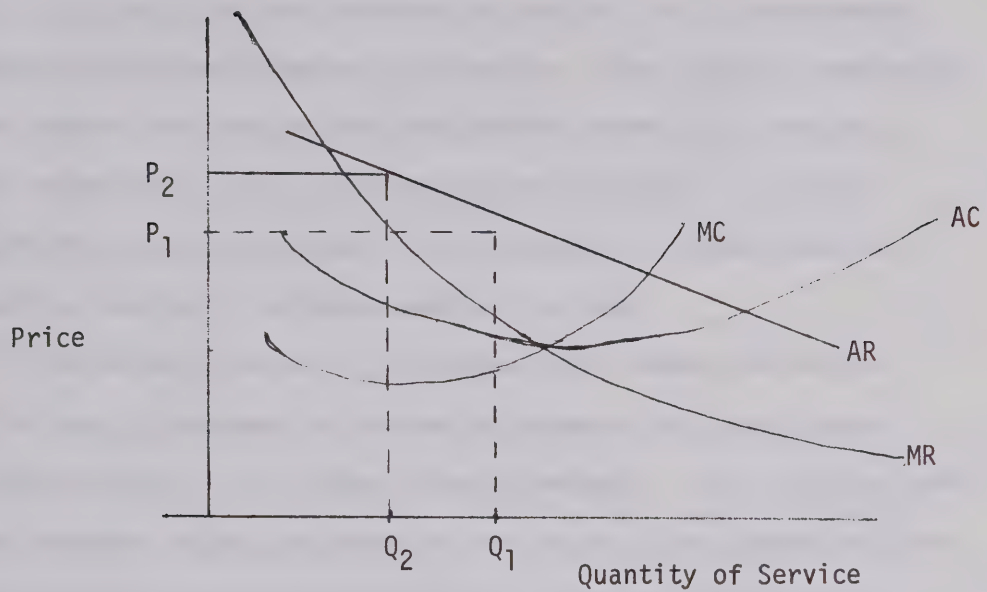
[1]James W. McKie. "The Regulation of Natural Gas." American Enterprise Association, Inc., Washington D.C., June, 1957, p. 5.



MC = Marginal Cost

MR = Marginal Revenue

AC = Average Cost

AR = Average Revenue

Fig. 5: A Monopoly Situation.

The Regulation of Natural Gas Pipe Lines

To obtain 'optimum, economic allocation' by a transmission company requires governmental intervention. The object of regulation is to achieve the results that free market competition produces in other industries, such as the appropriate expansion of capacity, limitation of profits, access of all consumers to supply and the correct rationing of available supply by price.[1]

The Natural Gas Act of 1938 placed the transportation and sale of gas at wholesale in interstate commerce for resale under the jurisdiction of the Federal Power Commission. This concerns interstate wholesale sales for resale to the public. The Commission does not have rate jurisdiction over "direct" sales by interstate pipe lines to ultimate consumers. Instead, these sales are predominantly to industrial customers, and the interfuel competition for the industrial market is so great that industrial buyers have no need for regulatory protection. The demand for these customers is quite elastic.

The Federal Power Commission established zoning regions whose indirect purpose was to control the area prices for gas. Up until this time a transmission company contracted independently with each utility for a sale price of gas. But now the federal Power Commission ruled that the prices charged to all utilities within one rate zone were to be set at a standard rate.

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[1] Ibid.

The Act authorized the Commission to determine the actual legitimate cost of pipe line properties for inclusion in a rate base. From an important series of decisions, the Federal Power Commission decided to adopt the public utility rate base standard for "captive" gas production.[1] This was not such a bad idea because, once pipe line companies' operations become regulated they are, in effect, public utilities themselves.

The Rate Base

The rate base is composed principally of the net (or depreciated) valuation of the public utility's tangible property, comprising the plant and equipment used and useful in serving the public. In addition the rate base includes an allowance for working capital and, depending on the circumstances, may also include amounts for the overhead costs of organizing the business, intangibles and going-concern value.[2] But the key issue in the determination of the rate base is the valuation of plant and equipment. Garfield and Lovejoy[3] emphasize this for two reasons:

(1) the valuation of plant and equipment is the largest component part of the rate base,

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[1]These decisions were upheld by the Supreme Court in FPC v. National Gas Pipelines Co. et al., 315 U.S. 575 (1942); FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944); and Colorado Interstate Gas Co. v. FPC, 324 U.S. 581 (1945), reported by McKie, op. cit., p. 18.

[2]Garfield and Lovejoy, op. cit., p. 56.

[3]Ibid.

(2) the particular valuation method employed whether actual cost less depreciation;[1] reproduction cost new less depreciation;[2] or "fair value";[3] can affect the size of this principal component.

Having determined the rate base, then these costs are incorporated into a formula to determine the cost of service. The cost of service basically is the sum of:-

(i) operating expenses;

(ii) depreciation expense;

(iii) taxes; and

(iv) a reasonable return on the net valuation on the property devoted to the public service (i.e., the rate base).

Rate Making

Rate making is the process which determines the price at which

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[1]This includes (a) historical cost-construction and acquisition costs less depreciation, (b) prudent investment - historical cost less any wasteful costs, or (c) original cost - total investment cost when first devoted to public service, less depreciation.

[2]The cost of duplicating the existing plant and equipment at recent average prices.

[3]Originated from the case of Smyth v. Ames - it is a composite method which considers both depreciated actual cost and reproduction cost new less depreciation, and other factors, with each factor given the weight judged appropriate.

gas may be sold under regulation. The public utility rate making formula is defined[1] as:-

Cost of Service = E + d + T + (V-D)R

where E = Operating Expenses

d = Depreciation Expense

T = Taxes

V = Gross valuation of the property serving the public

D = Accrued Depreciation

R = Rate of Return (a percentage)

This implies that a public utility under efficient and economic management requires revenues sufficient to cover expenses and taxes, and to provide a reasonable return on the net valuation of the property used and useful in serving the public.

With interstate natural gas transmission systems complications arise from the valuation of property due to the fact that plant investment averages about three times the annual gross operating revenues, thus indicating a slow rate of capital turnover.[2]

In addition, there is the question of the cost of service principle itself. Where a pipe line has non-jurisdictional business (such as firm and interruptible sales directly off the main line and not for resale), the F.P.C. will consider the overall cost of service for both jurisdictional and non-jurisdictional business. The Commission has received court approval of its right to consider the total operations

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[1] Garfield and Lovejoy, op. cit., p. 45.

[2] Ibid., p. 174.

of a pipe line as one step toward determining the cost of the regulated portion of the business.[1]

Thirdly, this writer questions the validity of the cost of service standard versus, for example, a discounted cash flow approach. Due to the long-term nature of a pipe line operation and the accompanying gas rate therefrom, it seems valid to suggest that some account be taken of the value of the dollar costs in the future when establishing the price which may be charged for gas at the present. This principle is backed up by the fact that some transmission companies are already using the discounted cash flow technique for internal decision making. They feel that the tool shows more accurate results over the long run than the cost of service does.[2]

But the introduction of discounted cash flow is opinion rather than fact. The Commission's formula for determining rates it will approve was set forth at length in a 1952 decision involving the rates of the Atlantic Seaboard Corporation.[3]

The Atlantic Seaboard Formula

After the total cost of service for the test year has been determined, the Atlantic Seaboard formula enters the rate-making picture.

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[1] Colorado Interstate Gas Co. v. FPC, 324 U.S. 581 (1945).

[2] This is suggested by the literature, e.g., P. S. Panos "LNG: Buy it or Own it?" American Gas Journal, August, 1966, p. 35; and Boyd M. Harnden, op. cit.

[3] Re Atlantic Seaboard Corp., 11 FPC 43; 94 PUR (NS) 235 (1952).

In applying the formula, there are the following steps:-[1]

(1) There is a functional segregation of total system costs into such categories as production, storage, transmission, distribution, and general costs.

(2) These costs are classified between demand (capacity) and commodity (volume) functions.

(3) The costs classified on a demand and commodity basis are allocated between jurisdictional and non-jurisdictional business.

(4) Rates are determined on the basis of the jurisdictional costs which may apply on a system-wide basis or to individual rate zones reflecting distance differentials.

An important characteristic of the Atlantic Seaboard formula is that, where conventionally demand costs are associated with fixed costs and the commodity charges with variable costs, here there is a requirement that the fixed cost items be distributed equally, on a 50-50 basis, to the demand and commodity categories. As a result, the commodity charge contains all of the variable costs plus 50 per cent of the fixed costs.

Finally, the jurisdictional rates are determined by relating allocated costs to demand and sales volumes. A typical picture is shown in Table II on page 36.[2]

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[1]Garfield and Lovejoy, op. cit., p. 182.

[2]Harnden, op. cit., p. 17.

TABLE II

FUNCTIONAL CLASSIFICATION OF COSTS REQUIRED FOR APPLICATION OF THE ATLANTIC SEABOARD FORMULA IN ORDER TO DETERMINE THE JURISDICTIONAL COST-OF-SERVICE

FUNCTION	CLASSIFICATION Percentages Applicable to Demand	 Commodity
Operating Expenses:		
Natural Gas Prod. & Gath.		100
Products Extraction		100
Exploration and Development		100
Other Gas Supply		100
Storage	*	*
Transmission	40	60
Customer Accounts	50	50
Sales	50	50
Administrative & General	50	50
Other:		
Depreciation	50	50
Depletion		100
Amortization	50	50
Taxes-Other than Income Taxes	50	50
Taxes-Federal Income	50	50
Taxes-State Income	50	50
Return**	50	50
Revenue Credits	___	100
Total Cost-of-Service	"Demand"	"Commodity"
(1) Demand Portion of the Jurisdictional Cost-of-Service	= MCFD Ratio x Total Cost-of-Service "Demand"	
(2) Commodity Portion of the Jurisdictional Cost-of-Service	= MMCFY Ratio x Total Cost-of-Service "Commodity"	
(3) Total Jurisdictional Cost-of-Service	= (1) + (2)	

*The percentage allocation of cost between demand and commodity categories is dependent on the type of storage service offered. Costs of storage designed to serve a peak seasonal requirement only, should be allocated on a 100 per cent demand basis. Costs of storage designed to provide a year-round service should be divided between the demand and commodity categories.

**Return allowed equals about 7 per cent times the Rate Base.

Relevance to the Model

Resulting from all this is a highly complex system to establish the price that a transmission company may charge its jurisdictional customers for the sale of gas in each rate zone. The effect of regulation is to establish a price per M.C.F. which is both an upper and a lower bound. Yet this price which is based on the cost of service must be competitive with other fuels. This means that in order to survive a transmission company must operate its business reasonably efficiently cost-wise so that the rate which is set is on a par with the going market rate in a particular area. The market rate is determined by the prices of competitive feeds. Therefore, what the model desires to accomplish is the realization of the maximum prices that can be charged to each class of customer in each area subject to the basic constraints of regulation and competition.

CHAPTER V

THE ANALYSIS OF THE MODEL

The Nature of Linear Programming

Linear programming deals with the problem of allocating limited resources among competing activities in an optimal manner. It uses a mathematical model to describe the problem of concern. "Linear" refers to the fact that all the mathematical functions are required to be of a linear nature; and "programming" is essentially a synonym for planning.

The advantages gained from the implementation of such a tool are basically the following:-

(1) Speed. It uses a quick algorithm called simplex to arrive at a solution,

(2) Accuracy. Its function is to maximize or minimize a set of variables in an optimal fashion.

However, there are also certain limitations attached to the tool which are elaborated on by Hillier and Lieberman.[1] These include the following:-

(1) Proportionality. Linear Programming (LP) does not allow the inclusion of variables of a non-linear nature.

(2) Additivity. LP requires that activities be additive with respect to the measure of effectiveness and each resource usage.

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[1] F. S. Hillier and G. J. Lieberman. "Introduction to Operations Research", Holden-Day, Inc., San Francisco, 1968, pp. 136-138.

(3) Divisibility. Fractional levels of the decision variables must be permissible.

(4) Determination. LP assumes that the coefficients of the variables can be accurately determined as known constants. In reality, they are frequently not constant, nor known.

Methodology

The procedure that was adopted for this study to set about generating optimum solutions for the model was as follows:

(1) A survey was made of the options provided by the IBM model 360/67 computer which included fortran IV, A.P.L.,[1] and M.P.S./360.[2]

(2) Concentration was given to A.P.L. and M.P.S./360 as these provided linear programming software ready to run.

(3) Of these two, M.P.S./360 was considered by the writer to be the more useful, as it has parametric programming functions built into it. In addition, more core can be used and a much more detailed analysis can be obtained by this application. Several runs were made to determine the format of the model.

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[1]Refers to "A Programming Language".

[2]Refers to "Mathematical Programming System". The explanation of this package is set out in the IBM manual number H20-0476.

(4) However, when the solutions were found to be trivial, a simpler approach, namely A.P.L., was adopted, because of the advantage to be gained from working on real time.

The L.P. function on A.P.L. is conversational and there is a core restriction made on the physical size of the problem to run. In addition, probably the primary fault with the function is that it provides just the solutions and no analysis whatsoever. But, where the solutions are trivial, no effective analysis can be done anyway. This was the justification for its application.

The function is operated on an IBM terminal by instructing the computer what to do through a series of typed commands. The format is standardized and must be followed to obtain solutions. The format is the following:

(1) "MAXIMIZE" or "MINIMIZE" ≠ =

(2) "SUBJECT TO"

(3) The variables must be labelled as Xi's

(4) "END"

Examples of this are shown on pages 43-47.

Upon the return of the typewriter carriage the computer will go to work and the output will follow. Examples of this are shown on pages 54-55.

The Formulation of the Model

Specifically, the problem is to maximize the total price that can be charged to each customer, for each rate zone, for the installation of a known storage alternative. The formulation is:

$$\text{Maximize } \neq = \sum_{i=1}^{9} Xi$$

Subject to:

$$Xi \geq \text{price} \quad (i = 1,2,3)$$

$$\sum_{i=1}^{3} Xi \leq \text{rate base}$$

$$Xi \leq \text{competitive fuels (for each rate zone)} \quad (i = 1,2,.....9)$$

$$Xi \geq 0 \quad (i = 1,2,.....9)$$

where:

X1, X2, X3 = Total prices charged to jurisdictional customers in rate zones 1, 2, 3 (which as previously outlined are:- (1) Mississippi, Louisiana; (2) Alabama; (3) Georgia).

X4, X5, X6 = Total prices charged to jurisdictional-direct customers in rate zones 1, 2, 3, where X4 ⇒ 1, X5 ⇒ 2, X6 ⇒ 3.

X7, X8, X9 = Total prices charged to direct customers in rate zones 1, 2, 3 where X7 ⇒ 1, X8 ⇒ 2, X9 ⇒ 3.

Price = Required price in ¢/MCF for the storage alternative generated by the simulation,[1] plus the cost of gas.

rate base = capital cost of the storage alternative (because purpose is for peak shaving 100 per cent is allowed) divided by the estimated amount of recoverable gas and by the portion allocated to jurisdictional customers - computed in ¢/MCF.

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[1]Harnden, op. cit., p. 94. The price is calculated as that average price which must be charged, which will equate the present value of the discounted cash flow with the present value of the capital investment over a 25-year period for each storage alternative where a weighted average cost of capital of 10 per cent is used as the discount factor. An example of this is shown in the Appendix on page 75.

Competitive fuels = the most competitive fuel (oil, coal, or gas) for each rate zone.

Analysis of the Model

Applying this, results in the following five models, shown on Tables III to VII on pages 43 to 47. Table III refers to the "best" prices to charge for a strategic aquifer; Table IV for a nuclear cavity; Table V for L.N.G.; and Tables VI and VII for combinations of these. There are thirteen constraints in each case. Because the constraints are of a comparatively trivial nature the models were programmed in A.P.L. on a conversational LP function using the simplex algorithm.

The first three constraints are concerned with the jurisdictional customers economic requirement that the average price charged to these customers in each zone must be greater than or equal to that price generated by the simulation.[1] If this is not the case, then there is no point in installing the storage because it will produce revenue at a lower rate than the pre-set standard and may lead to liquidation. The pre-set standard is based on the following:-

(1) The assumption that the data applied in the simulation[2] is for an economic installation.

(2) The interest rate for the borrowed capital (50 per cent of the capital required) is 7 per cent.

(3) A discount factor of 10 per cent calculated from a weighted-average cost of capital is reasonable.

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[1] Ibid.

[2] Ibid.

TABLE III

ALTERNATIVE 1: AN AQUIFER BASED ON TOTAL DELIVERABILITY OF 380 MMCFD AND TOTAL STORAGE CAPACITY OF 90,000 MMCF (in ¢/MCF)

MAXIMIZE

$Z=X1+X2+X3+X4+X5+X6+X7+X8+X9$

SUBJECT TO

$X1 \geq 69$

$X2 \geq 69$

$X3 \geq 69$

$X1+X2+X3 \leq 340.08$

$X1 \leq 180$

$X2 \leq 293$

$X3 \leq 164$

$X4 \leq 28.1$

$X5 \leq 22$

$X6 \leq 27$

$X7 \leq 28.1$

$X8 \leq 22$

$X9 \leq 27$

END

TABLE IV

ALTERNATIVE 2: A NUCLEAR CAVITY STORAGE BASED ON TOTAL DELIVERABILITY OF 146 MMCFD AND TOTAL STORAGE CAPACITY OF 3,000 MMCF (in ¢/MCF)

MAXIMIZE

$Z=X1+X2+X3+X4+X5+X6+X7+X8+X9$

SUBJECT TO

$X1 \geq 133$

$X2 \geq 133$

$X3 \geq 133$

$X1+X2+X3 \leq 1023.4$

$X1 \leq 244$

$X2 \leq 293$

$X3 \leq 164$

$X4 \leq 28.1$

$X5 \leq 22$

$X6 \leq 27$

$X7 \leq 28.1$

$X8 \leq 22$

$X9 \leq 27$

END

TABLE V

ALTERNATIVE 3: AN L.N.G. BASED ON TOTAL DELIVERABILITY OF 200 MMCFD AND TOTAL STORAGE CAPACITY OF 3,000 MMCF (IN ¢/MCF)

MAXIMIZE

$Z=X1+X2+X3+X4+X5+X6+X7+X8+X9$

SUBJECT TO

$X1 \geq 139$

$X2 \geq 139$

$X3 \geq 139$

$X1+X2+X3 \leq 1188$

$X1 \leq 250$

$X2 \leq 293$

$X3 \leq 164$

$X4 \leq 28.1$

$X5 \leq 22$

$X6 \leq 27$

$X7 \leq 28.1$

$X8 \leq 22$

$X9 \leq 27$

END

TABLE VI

ALTERNATIVE 4: A COMBINATION OF AQUIFER AND NUCLEAR STORAGE BASED ON TOTAL DELIVERABILITY OF 526 MMCFD AND TOTAL STORAGE CAPACITY OF 93,000 MMCF (in ¢/MCF)

MAXIMIZE

$Z=X1+X2+X3+X4+X5+X6+X7+X8+X9$

SUBJECT TO

$X1 \geq 83$

$X2 \geq 83$

$X3 \geq 83$

$X1+X2+X3 \leq 350.5$

$X1 \leq 194$

$X2 \leq 293$

$X3 \leq 164$

$X4 \leq 28.1$

$X5 \leq 22$

$X6 \leq 27$

$X7 \leq 28.1$

$X8 \leq 22$

$X9 \leq 27$

END

TABLE VII

ALTERNATIVE 5: A COMBINATION OF AQUIFER AND L.N.G. STORAGE BASED ON TOTAL DELIVERABILITY OF 580 MMCFD AND TOTAL STORAGE CAPACITY OF 93,000 MMCF (in ¢/MCF)

MAXIMIZE

$Z=X1+X2+X3+X4+X5+X6+X7+X8+X9$

SUBJECT TO

$X1 \geq 93$

$X2 \geq 93$

$X3 \geq 93$

$X1+X2+X3 \leq 363.95$

$X1 \leq 204$

$X2 \leq 293$

$X3 \leq 164$

$X4 \leq 28.1$

$X5 \leq 22$

$X6 \leq 27$

$X7 \leq 28.1$

$X8 \leq 22$

$X9 \leq 27$

END

The fourth equation states that the prices charged to the jurisdictional customers must be less than or equal to that amount allowed to be included in the rate base. It uses the data which is calculated as shown on Table VIII on page 49. By way of explanation:

(1) The capital cost of each alternative is taken directly from the simulation.[1]

(2) The volume of recoverable gas is estimated as a percentage of the total storage capacity for each alternative. This is substantiated in part from the literature[2] and in part from the staff of the Southern Natural Gas Company. The storage capacity is taken from the simulation[3] as a reasonable estimate of an economic capacity.

(3) The portion allocated to jurisdictional customers is calculated from the actual volume of sales to this classification of customer by the Southern Natural Gas Company,[4] which is representative of the industry. The appropriation is made only to jurisdictional customers because these are the only customers subjected to direct regulation.

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[1] Ibid.

[2] Coats, op. cit., p. 76.

[3] Harnden, op. cit.

[4] Southern Natural Gas Company, op. cit.

TABLE VIII

CALCULATION OF THE AMOUNT OF THE CAPITAL COST FOR EACH STORAGE ALTERNATIVE ALLOWED IN THE RATE BASE BASED ON THE COST OF SERVICE

(1)	(2)	(3) Recoverable Gas in MMCF		(4)	(5)	(6)
Alternative	Capital Cost	%	Amount	(2)/(3) in ¢/MCF	Portion allocated to jurisdictional customers (96%)	Multiply (5) by 3 in ¢/MCF
1	48,453,408	50%	45000	107.67	103.36	310.08
2	9,594,000	90%	2700	355.33	341.12	1023.36
3	12,127,600	98%	2940	412.50	396.00	1188.
4	58,047,424	51%	47700	121.70	116.83	350.5
5	60,581,024	52%	47940	126.37	121.32	363.95

(4) The last column is merely a multiplication of the result by three to help find the average price in each zone.

The next three equations represent the competitive fuel constraints for the jurisdictional customers in the three rate zones. The right-hand side data was furnished by the Southern Natural Gas Company[1] as being the prices charged by its competitors[2] for peak shaving gas in each zone. However, in rate zone 1, Southern has practically a monopoly situation for this service. So to arrive at a realistic figure, the computation is the addition of the current tariff and the price required by the simulation for each storage alternative, minus the cost of gas. This is shown on Table IX on page 51.

The next six equations also represent the competitive fuel constraints; the first three for jurisdictional-direct customers, and the rest for direct customers. The data supplied is for the most competitive fuel in each of the three zones, and is shown on Table X on page 52.

It is felt that these customers are not competing with the jurisdictional for peak-shaving gas. Rather, they will purchase gas out of storage, only if it is competitive with the current prices of existing substitute fuels in each area. The purpose is slightly different than that for the jurisdictional customers. The principal application of storage to these clients is to firm-up their demand requirements and in the long run, sell more gas to them.

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[1] Ibid.

[2] For example Transcontinental Pipeline Company.

TABLE IX

CALCULATION OF THE DATA REQUIRED FOR THE COMPETITIVE FUEL CONSTRAINT FOR JURISDICTIONAL CUSTOMERS IN RATE ZONE 1

Alternative	S.N.G.'s* own Charges for Rate Zone 1		Total	Plus the Required Price for Storage Minus the cost of Gas (23 cents)	= Total
	Demand	Commodity			
1	114	20	134	46	180
2	114	20	134	110	244
3	114	20	134	116	250
4	114	20	134	60	194
5	114	20	134	70	204

*For contract demand service

TABLE X

COMPETITIVE FUEL PRICES (1969) IN ¢/EQUIV BTU
(Furnished by the Southern Natural Gas Company)

Zone	Gas	Coal	Oil
1 Mississippi	28.1	30-33	28.6-35
2 Alabama	26-30	22-26	40-60
3 (Georgia	27	27-33	29-38
(South Carolina		30-40	40-60

CHAPTER VI

RESULTS AND CONCLUSIONS

The Results of the Models

The total prices which should be charged are shown on Tables 11-15 on pages 54 to 58. Because of the way the models were formulated the results are by and large trivial solutions. In this respect the competitive fuel constraints, especially those for the jurisdictional-direct and direct customers, are redundant and need not be included in the models. These results are shown at the upper bound on the constraints and are the same for each alternative. However, the reason for their inclusion is to act as a comparison and show the overall picture.

What is of prime importance is the constrained prices for jurisdictional customers in each zone. The reason for this, as was stated earlier, is the fact that by far the majority of the transmission company's business is transacted with the jurisdictional customers (see page 10), and by the nature of their contracts, their requirements must be satisfied ahead of any other customer group.

The results for jurisdictional customers for alternatives 1, 4 and 5 should not be taken too seriously. Because the coefficients of the objective function are unity for all X's there is an equal chance for any variable to be entered in the solution. Therefore, for example in alternative 1, there is no reason why the transmission

TABLE XI

OPTIMUM PRICES GENERATED FOR A STRATEGIC AQUIFER WITH TOTAL DELIVERABILITY OF 380 MMCFD AND TOTAL STORAGE CAPACITY OF 90,000 MMCF (in ¢/MCF)

OPTIMAL VALUE OF OBJECTIVE FUNCTION IS 494.28

VARIABLE 01* *AT LEVEL* 69

VARIABLE 02 *AT LEVEL* 107.08

VARIABLE 03 *AT LEVEL* 164

VARIABLE 04 *AT LEVEL* 28.1

VARIABLE 05 *AT LEVEL* 22

VARIABLE 06 *AT LEVEL* 27

VARIABLE 07 *AT LEVEL* 28.1

VARIABLE 08 *AT LEVEL* 22

VARIABLE 09 *AT LEVEL* 27

VARIABLE 11 *AT LEVEL* 38.08

VARIABLE 12 *AT LEVEL* 95

VARIABLE 14 *AT LEVEL* 111

VARIABLE 15 *AT LEVEL* 185.92

**WHERE VARIABLE* 01 *REFERS TO X*1, 02 *TO X*2, *ETC.*

TABLE XII

OPTIMUM PRICES GENERATED FOR A NUCLEAR CAVITY STORAGE WITH TOTAL DELIVERABILITY OF 146 MMCFD AND TOTAL STORAGE CAPACITY OF 3,000 MMCF (in ¢/MCF)

OPTIMAL VALUE OF OBJECTIVE FUNCTION IS 855.2

VARIABLE 01 *AT LEVEL* 244

VARIABLE 02 *AT LEVEL* 293

VARIABLE 03 *AT LEVEL* 164

VARIABLE 04 *AT LEVEL* 28.1

VARIABLE 05 *AT LEVEL* 22

VARIABLE 06 *AT LEVEL* 27

VARIABLE 07 *AT LEVEL* 28.1

VARIABLE 08 *AT LEVEL* 22

VARIABLE 09 *AT LEVEL* 27

VARIABLE 10 *AT LEVEL* 111

VARIABLE 11 *AT LEVEL* 160

VARIABLE 12 *AT LEVEL* 31

VARIABLE 13 *AT LEVEL* 322.4

TABLE XIII

OPTIMUM PRICES GENERATED FOR AN L.N.G. STORAGE WITH TOTAL DELIVERABILITY OF 200 MMCFD AND TOTAL STORAGE CAPACITY OF 3,000 MMCF (in ¢/MCF)

OPTIMAL VALUE OF OBJECTIVE FUNCTION IS 861.2

VARIABLE 01 *AT LEVEL* 250

VARIABLE 02 *AT LEVEL* 293

VARIABLE 03 *AT LEVEL* 164

VARIABLE 04 *AT LEVEL* 28.1

VARIABLE 05 *AT LEVEL* 22

VARIABLE 06 *AT LEVEL* 27

VARIABLE 07 *AT LEVEL* 28.1

VARIABLE 08 *AT LEVEL* 22

VARIABLE 09 *AT LEVEL* 27

VARIABLE 10 *AT LEVEL* 111

VARIABLE 11 *AT LEVEL* 154

VARIABLE 12 *AT LEVEL* 25

VARIABLE 13 *AT LEVEL* 481

TABLE XIV

OPTIMUM PRICES GENERATED FOR A COMBINATION OF AQUIFER AND NUCLEAR STORAGE WITH TOTAL DELIVERABILITY OF 526 MMCFD AND TOTAL STORAGE CAPACITY OF 93,000 MMCF (in ¢/MCF)

OPTIMAL VALUE OF OBJECTIVE FUNCTION IS 504.7

VARIABLE 01 *AT LEVEL* 83

VARIABLE 02 *AT LEVEL* 103.5

VARIABLE 03 *AT LEVEL* 164

VARIABLE 04 *AT LEVEL* 28.1

VARIABLE 05 *AT LEVEL* 22

VARIABLE 06 *AT LEVEL* 27

VARIABLE 07 *AT LEVEL* 28.1

VARIABLE 08 *AT LEVEL* 22

VARIABLE 09 *AT LEVEL* 27

VARIABLE 11 *AT LEVEL* 20.5

VARIABLE 12 *AT LEVEL* 81

VARIABLE 14 *AT LEVEL* 111

VARIABLE 15 *AT LEVEL* 189.5

TABLE XV

OPTIMUM PRICES GENERATED FOR A COMBINATION OF AQUIFER AND L.N.G. STORAGE WITH TOTAL DELIVERABILITY OF 580 MMCFD AND TOTAL STORAGE CAPACITY OF 93,000 (in ¢/MCF)

OPTIMAL VALUE OF OBJECTIVE FUNCTION IS 518.15

VARIABLE 01 *AT LEVEL* 93

VARIABLE 02 *AT LEVEL* 106.95

VARIABLE 03 *AT LEVEL* 164

VARIABLE 04 *AT LEVEL* 28.1

VARIABLE 05 *AT LEVEL* 22

VARIABLE 06 *AT LEVEL* 27

VARIABLE 07 *AT LEVEL* 28.1

VARIABLE 08 *AT LEVEL* 22

VARIABLE 09 *AT LEVEL* 27

VARIABLE 11 *AT LEVEL* 13.95

VARIABLE 12 *AT LEVEL* 71

VARIABLE 14 *AT LEVEL* 111

VARIABLE 15 *AT LEVEL* 186.05

company should charge 69¢/MCF in Zone 1 (L.L.)[1] and 164¢/MCF in Zone 3 (U.L.).[2] These results are dependent upon the programming of the simplex algorithm itself. The basic constraining factor in this case is the rate base constraint.

In the light of this then, the writer suggests that for each of these alternatives, the results are added and averaged as shown in Table XVI.

The results for jurisdictional customers for alternatives 2 and 3, are shown at the upper limits of the competitive fuel constraints, the same as for the other customer groups.

With the exception for alternatives 1, 4, and 5, it may be seen that all the prices generated are bounded only by the competitive fuel constraints.

The value of the objective function is, in itself, meaningless, but by way of comparison with other alternatives, it serves to point out the relative costliness of each installation.

What is tabulated so far is a series of total prices for each alternative. But what is more relevant perhaps is the breakdown into demand and commodity charges for rate-making purposes. The way this is done was through the price generated by the simulation.[3] The cost of gas is taken as a percentage of 'price' and the transmission costs added to make up the commodity charge. The balance of what remains is the demand charge.

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[1] L.L. = lower limit on the constraint.

[2] U.L. = upper limit on the constraint.

[3] Harnden, op. cit.

TABLE XVI

ADJUSTED TOTAL PRICES FOR JURISDICTIONAL CUSTOMERS FOR ALTERNATIVES 1, 4, 5

	BEFORE	AFTER
ALTERNATIVE 1		
Zone 1	69	113.36
Zone 2	107.08	113.36
Zone 3	164	113.36
	340.08	340.08
ALTERNATIVE 4		
Zone 1	83	116.84
Zone 2	103.5	116.83
Zone 3	164	116.83
	350.5	350.5
ALTERNATIVE 5		
Zone 1	93	121.32
Zone 2	106.95	121.32
Zone 3	164	121.31
	363.95	363.95

The cost of gas is assumed to remain constant at approximately 23¢/MCF. The transmission charges are dependent on the distance to the market area and may be computed as the incremental cost of compressor fuel. Harnden[1] applies the incremental compressor fuel used as a function of the amount of gas sent to storage, multiplies this by the cost of gas and divides by a 'rough approximation' for average transport distance to arrive at an incremental compressor fuel cost of .359¢/MCF/100 miles.

Developing on this a measurement in miles is calculated from the wellhead(s) to the major market in each rate zone provided these are centrally located. For the Southern Natural Gas Company this is calculated from the southern shore of Louisiana to Pickens, Birmingham, and Ocmulgee. The transmission costs are then computed as is shown on Table XVII on page 62.

The Results Shown as Demand and Commodity

These may be seen on Tables XVIII to XXII on pages 63 to 67.

Further Developments

Having obtained a set of prices for each alternative there is still the question of what further improvements could be made. It is a known fact that in business when the volume of sales increases, the overhead costs per unit decreases, hence sales can be made at a reduced selling price. For the model then, prices may be adjusted depending

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[1] Ibid., pp. 41-42.

TABLE XVII

CALCULATION OF TRANSMISSION COSTS FOR EACH RATE ZONE

DISTANCES	MILES	ZONE
Start to Pickens	290	1
Pickens to Birmingham	200	2
Birmingham to Ocmulgee	210	3
	700	

TRANSMISSION COSTS = .359¢/MCF/100 miles

$$\text{Zone 1} = \frac{290}{100} \times .359 \text{ cents} = 1.041¢/\text{MCF}$$

$$\text{Zone 2} = \frac{490}{100} \times .359 \text{ cents} = 1.759¢/\text{MCF}$$

$$\text{Zone 3} = \frac{700}{100} \times .359 \text{ cents} = 2.513¢/\text{MCF}$$

TABLE XVIII

PRICES TO CHARGE FOR THE INSTALLATION OF AN AQUIFER IN ¢/MCF

"PRICE" = 69

CUSTOMER	ZONE	DEMAND 33% + T*	COMMODITY 66%	TOTAL
Jurisdictional	1	38.431	74.929	113.36
Jurisdictional	2	39.549	73.811	113.36
Jurisdictional	3	40.303	73.057	113.36
Jurisdictional-Direct	1	10.407	17.693	28.1
Jurisdictional-Direct	2	9.092	12.908	22
Jurisdictional-Direct	3	11.513	15.487	27
Direct	1	10.407	17.693	28.1
Direct	2	9.092	12.908	22
Direct	3	11.513	15.487	27

*T = Transmission Costs

TABLE XIX

PRICES TO CHARGE FOR THE INSTALLATION OF NUCLEAR STORAGE
IN ¢/MCF

"PRICE" = 133

CUSTOMER	ZONE	DEMAND 17% + T	COMMODITY 83% + T	TOTAL
Jurisdictional	1	42.521	201.479	244
Jurisdictional	2	51.569	241.431	293
Jurisdictional	3	30.391	133.609	164
Jurisdictional-Direct	1	5.818	22.282	28.1
Jurisdictional-Direct	2	5.499	16.501	22
Jurisdictional-Direct	3	7.303	19.697	27
Direct	1	5.818	22.282	28.1
Direct	2	5.499	16.501	22
Direct	3	7.303	19.697	27

TABLE XX

PRICES TO CHARGE FOR THE INSTALLATION OF AN L.N.G.
IN ¢/MCF

"PRICE" = 139

CUSTOMER	ZONE	DEMAND 17% + T	COMMODITY 83% + T	TOTAL
Jurisdictional	1	43.541	206.459	250
Jurisdictional	2	51.569	241.431	293
Jurisdictional	3	30.391	133.609	164
Jurisdictional-Direct	1	5.818	22.282	28.1
Jurisdictional-Direct	2	5.499	16.501	22
Jurisdictional-Direct	3	7.303	19.697	27
Direct	1	5.818	22.282	28.1
Direct	2	5.499	16.501	22
Direct	3	7.303	19.697	27

TABLE XXI

PRICES TO CHARGE FOR THE INSTALLATION OF AN AQUIFER/NUCLEAR COMBINATION IN ¢/MCF

"PRICE" = 83

CUSTOMER	ZONE	DEMAND 28% + T	COMMODITY 72% + T	TOTAL
Jurisdictional	1	33.756	83.084	116.84
Jurisdictional	2	34.474	82.366	116.84
Jurisdictional	3	35.228	81.612	116.84
Jurisdictional-Direct	1	8.909	19.191	28.1
Jurisdictional-Direct	2	7.919	14.081	22
Jurisdictional-Direct	3	10.073	16.927	27
Direct	1	8.909	19.191	28.1
Direct	2	7.919	14.081	22
Direct	3	10.073	16.927	27

TABLE XXII

PRICES TO CHARGE FOR THE INSTALLATION OF AN AQUIFER/L.N.G. COMBINATION IN ¢/MCF

"PRICE" = 93

CUSTOMER	ZONE	DEMAND 25% + T	COMMODITY 75% + T	TOTAL
Jurisdictional	1	31.371	89.949	121.32
Jurisdictional	2	32.089	89.231	121.32
Jurisdictional	3	32.843	88.477	121.32
Jurisdictional-Direct	1	8.066	20.034	28.1
Jurisdictional-Direct	2	7.259	14.741	22
Jurisdictional-Direct	3	8.588	18.412	27
Direct	1	8.066	20.034	28.1
Direct	2	7.259	14.741	22
Direct	3	8.588	18.412	27

upon the volume of sales to each customer in each rate zone. This would lead to changes in the demand charge (fixed costs) to customers. The way to include this in the model is to apportion volume on a percentage basis as the coefficients of the constraint variables where relevant. The basic formulation of the model itself will not change.

The weather patterns for each area may be used as an alternative to volume to determine the coefficients of the variables. For example, in a comparison of two areas, where one has a colder mean temperature than the other, more importance could be weighted to it.

Another important consideration concerning volume is with respect to the prices already generated (shown on Tables XVIII to XXII on pages 63 to 67). The volume of deliverable gas for sale for each alternative has been estimated (see Chapter V). Provided this is less than or equal to pipe line capacity, which is revealed in a cursory glance, it is useful to determine where and to whom this gas will be sold based on the generated prices. The formulation for this is as follows:

$$\text{Maximize } \neq = \sum_{i=1}^{9} pixi$$

$$\text{s.t.} \quad \sum_{i=1}^{9} xi \leq \text{effective storage delivery}$$

$$xi \geq o \quad (i = 1, 2, \ldots, 9)$$

where: pi : the total price generated by the L.P. model for each customer for each rate zone.

xi : the volume sold to each customer in each rate zone.

effective storage delivery :
is shown as column 3 in Table VIII in Chapter V.

Programming this by the same method applied previously also results in a trivial solution, by virtue of the fact that because there is only one constraint equation there will only be one solution for each alternative. However, the solution generated in each case suggests that the sales of gas out of storage will be made to jurisdictional customers because they are prepared to pay more for it. The principal markets are found to be in rate zones 2 and 3 and this ties in with reality because here is where the majority of the populace is concentrated.

Further from this some parametric programming may be instituted on the R.H.S.[1] as both pipe line capacity and storage capacity increase over time. But because the solution is trivial no real advantage is gained from doing so.

Conclusion

Overall, there is the problem of regulation of all the fuels in the United States competing with each other as energy suppliers, none is so regulated as the natural gas industry. The regulations which have been discussed, form a series of complications for the interstate transmission company. This paper hoped to find a solution to the problems of regulation, or at least to stimulate new thought on the process of how gas prices are established. A model was developed to generate prices to charge for gas and to help one corporation towards optimal system operation. Hopefully, by applying the model successfully to one

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[1] Right Hand Side.

corporation, it may lead to general acceptance within the industry.

This model, in the opinion of the writer, has achieved what it set out to do. A set of realistic prices has been generated for each storage alternative. These should be useful for internal decision making within the company. They provide a good check on the existing operational prices because in most instances they directly reflect them. Most of the prices obtained are equivalent to the prices charged by competitors. This makes good sense, especially in a tightly-regulated industry where prices are, for the greater part, fixed.

As far as the model acting as a price-setting weapon, the writer is of the opinion that it has the competence to do so. It meets the conditions of the constraints both economic and legal and this seems the justification for the validity of the results. The model could be a quick, concise, and accurate method in deciding the prices to be charged for gas out of storage (and for that matter out of the general system itself). But there would be one major fault. The economic constraints rely on the prices of competitors. In some areas there are no substantial alternate fuels for consumption. What could result is a price-setting agreement among suppliers and the effect of legal regulation would be nullified. Instead of having governmental control, which is equitable, a system of monopoly pricing may develop. The way to avoid this is to impose strict controls over the means in deciding the prices to be charged by competitors.

The model is also useful in that it provides data to help the decision of which is the best alternative for the transmission company to adopt. The best alternative may be dependent on geologic formations and market requirements, but if these can be overcome, the model suggests

that the cheapest and hence most useful form of storage is the aquifer. After this comes the aquifer combinations with nuclear, and L.N.G.; then finally the nuclear cavity and L.N.G. separately. But it must be remembered that the volume of recoverable gas varies substantially with each alternative. Where only a small volume of gas is required from storage it may be better, especially in the short run, to install an L.N.G. for example. Certainly, it would be less wasteful costwise if the venture was not a successful one.

GLOSSARY OF TERMS

B.C.F.	:	Billion Cubic Feet
B.T.U.	:	British Thermal Unit
F.P.C.	:	Federal Power Commission
L.L.	:	Lower Limit
L.P.	:	Linear Programming
M.C.F.	:	Thousand Cubic Feet
M.M.C.F.	:	Million Cubic Feet
M.M.C.F.D.	:	Million Cubic Feet per Day
R.H.S.	:	Right Hand Side
U.L.	:	Upper Limit

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APPENDIX A

EXAMPLE OF OUTPUT USED TO OBTAIN "PRICE" TAKEN FROM B. M. HARNDEN, OP. CIT., PAGE 85
(THIS EXAMPLE IS FOR THE AQUIFER-NUCLEAR COMBINATION SHOWN IN THE STUDY AS ALTERNATIVE 4)

STRATEGIC ALTERNATIVE NUMBER 5

STRATEGIC VOLUME AS A COMBINATION OF AQUIFER VOLUME FOR INTERRUPTIBLE SERVICE AND NUCLEAR VOLUME FOR PEAK SHAVING SERVICE

YEAR	STRATEGIC VOLUME MMCF	PIPELINE UTILIZATION FACTOR	WITHDRAWAL UTILIZATION FACTOR	AVERAGE LOAD FACTOR WITH STORAGE	AVERAGE LOAD FACTOR NO STORAGE	OFF PEAK LOAD FACTOR WITH STORAGE	OFF PEAK LOAD FACTOR NO STORAGE
1969	0.0	0.0	0.0	1.080	1.080	1.136	1.136
1970	2205.00	0.050	0.002	1.091	1.087	1.160	1.154
1971	2310.00	0.039	0.004	1.076	1.073	1.126	1.121
1972	6680.00	0.170	0.033	1.101	1.089	1.177	1.157
1973	13800.00	0.326	0.118	1.123	1.105	1.228	1.194
1974	24515.00	0.424	0.247	1.114	1.083	1.194	1.142
1975	35380.00	0.756	0.500	1.141	1.097	1.254	1.175
1976	41460.00	1.082	0.769	1.160	1.108	1.302	1.205
1977	47542.00	0.817	0.611	1.145	1.090	1.256	1.159
1978	53622.00	1.104	0.857	1.168	1.105	1.310	1.195
1979	59702.00	1.502	1.200	1.186	1.117	1.358	1.224

ECONOMIC ANALYSIS BASED ON PRESENT VALUE OF NET CASH FLOW

REQUIRED CAPITAL BASED ON TOTAL DELIVERABILITY OF 526.MMCFD AND TOTAL STORAGE CAPACITY OF 93000.MMCF

YEAR	REVENUE $	INCREMENTAL COST $	DEPR $	INTEREST $	INSURANCE $	AD VALOREM TAX $	INCOME BEFORE TAXES $	TAXES BEFORE INV TAX CR. $	INVESTMENT TAX CR. $	INCOME AFTER TAXES $	NET CASH FLOW $	CAPITAL INVESTMENT $
1969	0.	1669441.	939693.	822231.	37588.	234923.	-3703874.	-1845270.	822231.	-1036373.	-96680.	23492320.
1970	63273.	237288.	1184268.	1036235.	47371.	296067.	-2737952.	-1364047.	214004.	-1159901.	24367.	6114390.
1971	126546.	285536.	1390697.	1216860.	55628.	347674.	-3169887.	-1579237.	180626.	-1410023.	-19326.	5160750.
1972	1012366.	1079499.	1594750.	1395406.	63790.	398687.	-3515705.	-1753517.	178546.	-1587641.	7109.	5101320.
1973	3012993.	1937257.	1761358.	1541188.	70454.	440340.	-2737603.	-1363873.	145783.	-1227947.	533411.	4165220.
1974	8616557.	3838578.	1867228.	1633824.	74689.	466807.	735430.	366391.	92636.	461675.	2328903.	2646750.
1975	14088756.	5729404.	1958787.	1713939.	78351.	489697.	4118577.	2051875.	80115.	2146816.	4105603.	2289000.
1976	17752544.	6945452.	2068187.	1809663.	82727.	517047.	6329467.	3153340.	95725.	3271851.	5340038.	2735000.
1977	21417552.	8161872.	2164637.	1894057.	86585.	541159.	8569240.	4269195.	84394.	4384438.	6549075.	2411250.
1978	25081360.	9377921.	2248936.	1967819.	89957.	562234.	10834491.	5397743.	73762.	5510510.	7759446.	2107500.
1979	28745152.	10593969.	2321896.	2031659.	92876.	580474.	13124262.	6538507.	63840.	6649594.	8971490.	1824000.
1980	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1981	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1982	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1983	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1984	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1985	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1986	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1987	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1988	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1989	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1990	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1991	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1992	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	0.
1993	28745152.	9513969.	2321896.	0.	92876.	580474.	16235910.	8088730.	0.	8147180.	10469076.	-7209900.
										TOTAL $	182070432.	58047424.

INTEREST RATE USED 0.07

COST OF CAPITAL USED 0.10 PRICE REQUIRED 0.60 $ PER MCF PRESENT VALUE $ 42111216. 42111264.

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